2011 Annual Information Form

March 20, 2012

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GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means the board of directors of Whitecap.

Compass means Compass Petroleum Ltd.

Midway means Midway Energy Ltd.

Onyx means Onyx 2006 Inc.

Shareholders means holders of our Common Shares.

Spitfire means Spitfire Energy Inc.

Spry means Spry Energy Ltd.

Whitecap, **we**, **us, our** or the **Corporation** means Whitecap Resources Inc.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 29, 2012 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2011.

NI 51-101 means National Instrument 51-101– *Standards of Disclosure for Oil and Natural Gas Activities*.

Securities

Common Shares means our common shares, as presently constituted.

Pre-Acquisition Shares means our common shares as constituted immediately prior to the reverse takeover transaction and subsequent amalgamation with Spitfire, whereby each Pre-Acquisition Share was exchanged for 8.33 Pre-Consolidated Shares.

Pre-Consolidated Shares means our common shares as constituted immediately prior to being consolidated on a basis of 10 to 1 on October 15, 2010.

Spitfire Shares means the common shares of Spitfire prior to the amalgamation of Whitecap and Spitfire on July 1, 2010.

Other

Credit Facility means our extendible revolving credit facility with a syndicate of lenders.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	thousand stock tank barrels of oil
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MBoe	thousand barrels of oil equivalent.
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business – Recent Developments – Capital Program*" as to our 2012 capital program; "*General Development of Our Business – History and Development – Recent Developments – Midway Acquisition*" as to the estimated purchase price of the acquisition of Midway, the expected closing date of the Arrangement, agreements to be entered into with the holders of Midway Options and Midway Incentive Warrants (as defined herein) and the use of proceeds of the Offering (as defined herein); *General Development of Our Business – History and Development – Recent Developments – Credit Facility*" as to the anticipated increase in our Credit Facility in connection with the Arrangement; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan and strategy; "*General Description of Our Business – Cyclical and Seasonal Impact of Industry*" as to the impact of our price risk management programs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow, debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development plans and opportunities, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; "*Changes to Reserves Data*" as to the reserves and future net revenue from the reserves acquired pursuant to the Compass acquisition, "*Description of Our Capital Structure*" as to the anticipated increase in our Credit Facility in connection with the Arrangement; and "*Dividend Policy*" as to our dividend policy.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- waterflood implementation opportunities and the results therefrom;
- recovery factors;
- well completions and the timing thereof;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- matters relating to the Arrangement (as defined herein) and offering of Units (as defined herein), including expected closing dates, conditions to closing and the effects thereof on the Corporation's financial position;
- matters in regards to the Credit Facility (as defined herein) including expected increases to the borrowing base thereof;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;

- treatment under governmental regulatory regimes and tax laws;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- expected changes in regulatory regimes in respect of royalty curves and regulatory improvements and the effects of such changes;
- plans to expand recovery from certain of our properties; and
- our business and acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility in market prices for oil and natural gas and foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions (including the Acquisition);
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; completion of the Acquisition; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets and is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

NOTE ON SHARE REFERENCES

On June 25, 2010 we completed the reverse takeover of Spitfire pursuant to which Spitfire acquired all of our issued and outstanding Pre-Acquisition Shares on the basis of 8.33 Spitfire Shares for each Pre-Acquisition Share. Unless otherwise noted, references in this Annual Information Form to our Pre-Acquisition Shares are on a pre-reverse takeover basis while references to our Pre-Consolidated Shares and Common Shares are on a post reverse takeover basis. Readers should multiply any referenced number of Pre-Acquisition Shares or securities to acquire Pre-Acquisition Shares by 8.33 to arrive at the equivalent number of Pre-Consolidated Shares or securities to acquire Pre-Consolidated Shares. In addition, readers should divide the issuance price of any Pre-Acquisition Share or the exercise price of any securities to acquire Pre-Acquisition Shares by 8.33 to arrive at the equivalent issuance price or exercise price for Pre-Consolidated Shares or securities to acquire Pre-Consolidated Shares.

On October 15, 2010 we effected a consolidation of our common shares on the basis of ten Pre-Consolidation Shares for every one Common Share. All references to Common Shares herein are to our common shares are presently constituted on the post-consolidated basis and all references herein to Pre-Consolidated Shares are to our common shares prior to the October 15, 2010 consolidation. Readers should divide any referenced number of Pre-Consolidated Shares by a factor of 10 to arrive at the equivalent number of Common Shares.

WHITECAP RESOURCES INC.

General

We are a junior oil and natural gas company engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in the Peace River Arch area of Alberta, West Central Alberta and Southwest and Southeast Saskatchewan.

We are the resulting entity following the completion of the reverse takeover of Spitfire and subsequent amalgamation with Spitfire on July 1, 2010 to form "Whitecap Resources Inc.". See "*General Development of Our Business – History and Development*".

Spitfire was incorporated under the *Business Corporations Act* (Alberta) on August 30, 2001. On November 6, 2001, Spitfire amended and restated its articles to change its authorized share structure to include an unlimited number of Spitfire Shares and an unlimited number of preferred shares. On March 31, 2004, Spitfire amalgamated pursuant to the *Business Corporations Act* (Alberta) with its wholly-owned subsidiary, Cashel Resources Inc. to form the amalgamated corporation, Spitfire Energy Ltd. On April 1, 2005, Spitfire purchased all of the issued and outstanding shares of, and then amalgamated with a private oil and gas company, Spitfire Exploration Ltd. pursuant to the *Business Corporations Act* (Alberta) to form Spitfire.

We were incorporated under the *Business Corporations Act* (Alberta) on June 3, 2008 as "1405340 Alberta Ltd.". On September 2, 2008 we amended our articles to change our name from 1405340 Alberta Ltd. to "Whitecap Resources Inc." and we commenced operations on September 17, 2009.

On July 1, 2010, we filed articles of amalgamation to effect the amalgamation of Spitfire and us. On July 30, 2010, we amalgamated pursuant to the *Business Corporations Act* (Alberta) with our wholly owned subsidiary, Onyx.

On October 15, 2010 we filed articles of amendment to effect a consolidation of our Common Shares on a basis of 10 Pre-Consolidation Shares for every 1 Common Share. The consolidation was approved by our Shareholders at our annual general and special meeting held on September 14, 2010.

On April 20, 2011, we amalgamated pursuant to the *Business Corporations Act* (Alberta) with our wholly owned subsidiary, Spry. On February 10, 2012, we amalgamated pursuant to the *Business Corporations Act* (Alberta) with our wholly owned subsidiary, Compass.

Our head office is located at Suite 500, 222 – 3rd Avenue S.W., Calgary, Alberta, T2P 0B4 and our registered office is located at Suite 2400, 525 - 8th Avenue S.W. Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

In August of 2009 we issued $10 million principal amount of 8% subordinated secured convertible debentures due September 30, 2012. On December 7, 2010, the convertible debentures were converted into 3,472,223 Common Shares in accordance with their terms.

In September of 2009 we obtained an operating loan facility in the amount of $25 million from a Canadian financial institution and closed a brokered private placement financing of 18 million Pre-Acquisition Shares at a price of $2.00 per share for gross proceeds of $36 million. In addition, on September 17, 2009 we closed an acquisition of oil and gas properties in the Peach River Arch area of Alberta for $58 million in cash prior to normal closing adjustments. Upon the closing of this acquisition we commenced operations. We were not a reporting issuer at the time of this acquisition and as such no business acquisition report was required for this acquisition.

On November 18, 2009 we closed a private placement financing of 382,000 Pre-Acquisition Shares at a price of $2.00 per share for total gross proceeds of $764,000.

On June 25, 2010 we completed the reverse takeover transaction with Spitfire which consisted of: (i) Spitfire acquiring all of our issued and outstanding Pre-Acquisition Shares on the basis of 8.33 Spitfire Shares for each Pre-Acquisition Share; (ii) the completion of a private placement of: (a) 16,000,000 units at a price of $0.25 per unit, with each unit comprised of one Pre-Consolidated Share and one warrant, each such warrant entitling the holder to purchase one Pre-Consolidated Share at a price of $0.25 for a period of 5 years; and (b) 15,000,000 Pre-Consolidated Shares at a price of $0.25 per Pre-Consolidated Share; and (iii) the board of directors of Spitfire was replaced with our Board of Directors and the officers of Spitfire were replaced with our management team. See "*Directors and Officers*".

On July 30, 2010, we acquired all of the issued and outstanding common shares of Onyx for an aggregate purchase price of approximately $52 million which included $40.5 million payable in cash to the shareholders of Onyx and the assumption of approximately $11.0 million of total liabilities. The purchase price for the acquisition was funded in part through the net proceeds of an offering of 89,000,000 subscription receipts issued at a price of $0.45 per subscription receipt for aggregate gross proceeds of $40,050,000. Each subscription receipt entitled the holder to receive, without payment of additional consideration or further action, one Pre-Consolidated Share upon the closing of the acquisition of Onyx. The offering of subscription receipts closed on July 30, 2010 and the subscription receipts were converted to Pre-Consolidated Shares following the closing of the Onyx acquisition. For further information with respect to the acquisition of Onyx, see the business acquisition report relating to the acquisition, dated September 15, 2010 and filed September 27, 2010, which is available on our SEDAR profile at www.sedar.com.

On October 15, 2010 we filed articles of amendment to effect a consolidation of our Common Shares on a basis of 10 Pre-Consolidation Shares for every 1 Common Share.

On October 18, 2010 our Common Shares commenced trading on the facilities of the Toronto Stock Exchange and were concurrently delisted from the TSX Venture Exchange.

On December 22, 2010 we completed an equity issue of 6,900,000 Common Shares on a bought deal basis at a price of $5.85 per Common Share. The net proceeds of the offering were initially used to partially repay outstanding indebtedness under our Credit Facility and were subsequently redrawn to finance the $25 million acquisition of oil and gas assets in our core Valhalla North property described below.

On January 14, 2011, we closed the acquisition of light oil weighted properties located in our core Valhalla North property ("**Valhalla Assets**") for the purchase price of $50 million (the "**Valhalla Asset Acquisition**"). Pursuant to an area of mutual interest with a joint venture partner (the "**Partner**"), the Partner elected to participate in the Valhalla Asset Acquisition to the effect that Whitecap and the Partner jointly purchased the Valhalla Assets, each as to an undivided 50% interest and paid 50% of the $50 million purchase price (being $25 million each). For further information with respect to the Valhalla Asset Acquisition, see the business acquisition report relating to the acquisition, which is available on our SEDAR profile at www.sedar.com.

On April 20, 2011, we acquired all of the issued and outstanding common shares of Spry for $130,898,000 in cash and the issuance of an aggregate of 8,228,023 Common Shares. We also assumed the debt and working capital of Spry, estimated at $36.0 million as at March 1, 2011. The acquisition of Spry was partially funded through the issuance of 22,000,000 subscription receipts at $6.80 per subscription receipt (including 2,000,000 subscription receipts issued pursuant to the exercise by the underwriters of their over-allotment option) for gross proceeds of $149.6 million. Concurrent with the closing of the acquisition of Spry on April 20, 2011, the subscription receipts of Whitecap were exchanged for Common Shares. For further information with respect to the Spry acquisition, see the business acquisition report relating to the acquisition, which is available on our SEDAR profile at www.sedar.com.

Recent Developments

Compass Acquisition

On February 10, 2012, we acquired all of the issued and outstanding common shares of Compass for $14.0 million in cash and the issuance of an aggregate of 10.9 million Common Shares. We also assumed the positive working capital of Compass, estimated at $1.3 million (net of transaction costs) as at November 30, 2011. In connection with the acquisition of Compass, the borrowing base of the Credit Facility was increased from $190 million to $250 million. The assets acquired by us pursuant to the acquisition consisted of operated, high working interest light oil assets located predominately in Dodsland/Kindersley area of West Central Saskatchewan with the majority of production and reserves focused in the Viking formation and represented a new light oil resource area for us. For further information with respect to the Compass acquisition, see the business acquisition report relating to the acquisition, which is available on our SEDAR profile at www.sedar.com. For further details relating to the reserves acquired by us pursuant to the Compass acquisition, see "*Changes to Reserves Data*" below.

Capital Program

We have established a 2012 capital program of approximately $185 million to fund our development activities in 2012. Our 2012 capital program does not include any new acquisition opportunities, including the acquisition of Midway described below.

Midway Acquisition

On February 28, 2012 we announced that we had entered into an arrangement agreement (the "**Arrangement Agreement**") with Midway pursuant to which Whitecap has agreed to acquire all of the issued and outstanding class A common shares of Midway ("**Midway Shares**") for a purchase price of approximately $550.3 million, including the assumption of Midway's net debt and working capital deficit, estimated at $111.7 million as at February 28, 2012 (the "**Arrangement**"). Under the terms of the Arrangement Agreement, holders of Midway Shares ("**Midway Shareholders**") will receive, for each Midway Share held, at the election of the holder: (i) 0.4802 of a Common Share ("**Share Consideration**"); or (ii) $4.85 in cash ("**Cash Consideration**"); or (iii) a combination of Share Consideration and Cash Consideration, provided that the aggregate amount of cash paid to Midway Shareholders in exchange for their Midway Shares will not exceed $111.2 million (provided that such amount shall be adjusted upwards by $1.20 for each Midway Placement Warrant (as defined below) that is exercised prior to the effective time of the Arrangement) and the aggregate number of Common Shares issued to Midway Shareholders in exchange for their Midway Shares will not exceed 33.5 million Common Shares (provided that such amount shall be adjusted upwards by 0.3614 of a Common Share for each Midway Placement Warrant that is exercised prior to the effective time of the Arrangement), subject in each case to proration. In connection with the Arrangement and by approval of the board of directors of Midway, the outstanding stock options to purchase common shares of Midway ("**Midway Options**") and Midway Incentive Warrants (as defined below) will become fully vested upon the Arrangement being approved by Midway Shareholders. Midway expects to enter into agreements with all of the holders of the outstanding Midway Options as well as holders of incentive warrants to purchase Midway Shares ("**Midway Incentive Warrants**") pursuant to which such holders will agree, prior to the effective time of the Arrangement, to either: (i) exercise their Midway Options and/or Midway Incentive Warrants in accordance with their terms; or (ii) surrender their Midway Options and/or Midway Incentive Warrants for a number of Midway Shares equal to the "in the money" amount of all of the Midway Options and/or Midway Incentive Warrants held by such person with the number of Midway Shares to be issued to such person being equal to $4.85 multiplied by the number of Midway Shares issuable pursuant to the exercise of such Midway Options and/or Midway Incentive Warrants less the aggregate exercise price of all such Midway Options and/or Midway Incentive Warrants, divided by $4.85.

All of the directors and officers of Midway, who collectively hold approximately 5% of the outstanding Midway Shares (on a non-diluted basis), have signed support agreements pursuant to which they have agreed to vote their respective shares held by them in favour of the Arrangement. Certain officers of Midway have also agreed to enter into area of exclusion agreements pursuant to which such persons will agree, among other things, with Whitecap not to engage in or participate in certain oil and gas activities in an agreed upon geographical area, subject to certain exceptions.

Conditions to closing the Arrangement under the Arrangement Agreement include, among other things, the following: (i) closing shall have occurred on or before May 31, 2012; (ii) all necessary regulatory, governmental and third party approvals and consents shall have been obtained, including the approval of the Toronto Stock Exchange, approvals under the *Competition Act* (Canada) and, the approval of the Court of Queen's Bench of Alberta; (iii) the approval of at least two thirds of Midway Shareholders and Midway Placement Warrantholders, voting together as a single class in person or by proxy at a meeting of Midway Shareholders and Midway Placement Warrantholders (the "**Midway Meeting**") scheduled for April 20, 2012, the approval of at least a majority of Midway Shareholders voting in person or by proxy at the Midway Meeting, and the approval of at least a majority of Midway Shareholders voting in person or by proxy at the Midway Meeting, after excluding the votes that may not be included in determining "minority approval" for a "business combination" pursuant to Multilateral Instrument 61-101 – *Protection of Minority Shareholders in Special Transactions*; (iv) the approval of the Arrangement and the issuance of the Common Shares thereunder (in accordance with the rules and policies of the Toronto Stock Exchange) by at least a majority of the shareholders of Whitecap voting in person or by proxy at the meeting of the shareholders of Whitecap scheduled for April 20, 2012; (v) no material adverse change respecting Midway or Whitecap shall have occurred; (v) Midway's debt, as at February 28, 2012 shall not exceed $111.7 million; (vi) all Midway Options and Midway Incentive Warrants shall have been exercised or surrendered pursuant to their terms; and (vii) Midway Shareholders and holders of Midway Placement Warrants holding no more than 5.0% of the outstanding Midway Shares and Midway Placement Warrants shall have exercised rights of dissent in respect of the Arrangement that have not been withdrawn as at the effective date of the Arrangement.

The Arrangement is expected to close on or about April 20, 2012 or such other date as Whitecap and Midway may agree but not later than May 31, 2012.

In connection with the Arrangement, Whitecap has entered into an agreement with GMP Securities L.P. and National Bank Financial Inc., as co-lead underwriters on their own behalf and on behalf of Macquarie Capital Markets Canada Ltd., Dundee Securities Ltd., FirstEnergy Capital Corp., Cormark Securities Inc., Scotia Capital Inc. and Desjardins Securities Inc. (collectively, the "**Underwriters**") pursuant to which the Underwriters have agreed to purchase for resale to the public, on a bought deal basis, 5,941,000 units ("**Units**") at a price of $20.20 per Unit, each Unit comprised of one subscription receipt ("**Subscription Receipt**") at a price of $10.10 per Subscription Receipt and one Common Share at a price of 10.10 per Common Share (the "**Offering**"). The net proceeds of the Offering will be used to fund the cash portion of the purchase price of the Arrangement, with any excess funds to be used to reduce indebtedness under the Credit Facility. Whitecap has also granted to the Underwriters an option (the "**Over-allotment Option**") to purchase up to an additional 891,150 Units provided that if the Over-allotment Option is exercised after the completion of the Arrangement, Common Shares shall be issued instead of Units, at a price of $20.20 per Unit (or Common Shares, as applicable), exercisable from time to time, in whole or in part, on or within 30 days following closing of the Offering, to cover over-allotments, if any, and for market stabilization purposes.

We completed the Offering on March 19, 2012 and issued 5,941,000 Units pursuant thereto. The proceeds from the sale of the Subscription Receipts comprising the Units (the "**Escrowed Funds**") are being held in escrow pursuant to a subscription receipt agreement (the "**Subscription Receipt Agreement**") and invested in short-term obligations of, or guaranteed by, the Government of Canada (or other approved investments) pending delivery by Whitecap to the Underwriters of a certificate to the effect that all conditions necessary to close the Arrangement (other than payment of the purchase price) have been completed (the "**Escrow Condition**"). Upon the satisfaction of the Escrow Condition on or before 5:00 p.m. (Calgary time) on May 15, 2012 or such later date as the Underwriters have elected, the Escrowed Funds and the interest earned thereon will be released to Whitecap and each holder of Subscription Receipts will receive one Common Share for each Subscription Receipt held, without payment of additional consideration or further action. Whitecap will utilize the Escrowed Funds to pay the cash portion of the purchase price. If the Arrangement is not completed by May 15, 2012 and the Underwriters have not elected to extend such date, the Arrangement Agreement is terminated in accordance with its terms at any earlier time, or Whitecap has advised the Underwriters or announced to the public that it does not intend to proceed with the Arrangement, holders of Subscription Receipts will be entitled to receive an amount equal to the full subscription price attributable to the Subscription Receipts and their pro rata entitlement to the interest accrued on the Escrowed Funds.

Credit Facility

We currently have a $250 million extendible revolving Credit Facility that consists of a $25 million operating line and a $225 million syndicated facility. The Credit Facility is a borrowing base facility subject to semi-annual review by the lenders, with the next review scheduled for May 2012. In addition, we anticipate increasing the Credit Facility to $400 million in connection with the Arrangement. See "*Description of our Capital Structure – Credit Facility*" and "*Risk Factors – Credit Facility Arrangements*".

Significant Acquisitions

The completion of the Valhalla Asset Acquisition on January 14, 2011 constituted a significant acquisition under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. We filed a business acquisition report regarding the Valhalla Asset Acquisition dated March 11, 2011 and filed March 14, 2011, which is available on our SEDAR profile at www.sedar.com.

The completion of the acquisition of Spry on April 20, 2011 constituted a significant acquisition under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. We filed a business acquisition report regarding the acquisition of Spry dated May 4, 2011 and filed May 6, 2011, which is available on our SEDAR profile at www.sedar.com.

The completion of the acquisition of Compass on February 10, 2012 constituted a significant acquisition under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. We filed a business acquisition report regarding the acquisition of Compass dated February 14, 2012 and filed February 14, 2012, which is available on our SEDAR profile at www.sedar.com.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. Since inception we have executed our business plan by pursuing strategic acquisitions and carrying out development programs focusing on our core properties in the Peace River Arch area of Northwest Alberta, West Central Alberta and Saskatchewan. Once a property has been acquired, we pursue optimization and ongoing development and expansion opportunities.

We apply our technical and operating expertise within our core properties with a disciplined approach based on the following principles:

- all employees are Shareholders;
- light oil focus;
- hold a high working interest;
- per share long-term growth;
- efficient cashflow reinvestment;
- field level operational focus;
- strategic acquisitions set-up future organic growth; and
- responsible and effective debt management.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers ("**CAPP**"). Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program, and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2011, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2012 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Facility which has an annual renewal date in May of 2012. See "*Risk Factors – Credit Facility Arrangements*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2011, we employed 36 full-time employees, including 34 office and 2 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 29, 2012. The statement is effective as of December 31, 2011 and the preparation date of the statement is February 29, 2012. The Report Of Management And Directors On Oil and Gas Disclosure in Form 51-101F3 and the Report On Reserves Data By Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2011 as contained in the McDaniel Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The McDaniel Report has been prepared in accordance with the standards contained in the COGEH Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. **The reserves data below does not include reserves acquired by Whitecap subsequent to year end pursuant to the Compass acquisition (see "*Changes to Reserves Data*" below) and the reserves that will be acquired by Whitecap in connection with the Arrangement (assuming the Arrangement is completed).** See "*General Development of Our Business – Recent Developments – Compass Acquisition*" and "*General Development of Our Business – Recent Developments – Midway Acquisition*",

All of our reserves are in Canada and, specifically, in the Provinces of Alberta and Saskatchewan.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our consolidated financial statements for the year ended December 31, 2011 should be consulted for additional information regarding our taxes.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS**

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	10,021.0	8,311.8	130.8	110.5	25,469.2	21,379.6	657.9	448.3
Developed Non-Producing	507.1	442.9	23.3	18.7	2,919.5	2,569.8	63.4	45.0
Undeveloped	7,699.4	6274.3	121.1	110.2	8,616.5	7,806.7	233.7	185.2
TOTAL PROVED	18,227.5	15,029.1	275.2	239.4	37,005.3	31,756.1	955.0	678.5
PROBABLE	9,015.0	7,179.4	149.3	129.8	19,801.8	16,801.1	489.2	326.0
TOTAL PROVED PLUS PROBABLE	27,242.5	22,208.5	424.5	369.2	56,807.1	48,557.2	1,444.2	1,004.5

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe and $/bbl
PROVED:						
Developed Producing	684,580	509,419	408,491	344,061	299,680	27.13
Developed Non-Producing	35,840	29,140	24,661	21,487	19,131	22.83
Undeveloped	359,908	197,703	119,196	74,266	45,611	12.56
TOTAL PROVED	1,080,328	736,262	552,348	439,814	364,422	21.55
PROBABLE	650,202	281,020	153,799	96,733	66,053	11.87
TOTAL PROVED PLUS PROBABLE	1,730,530	1,017,282	706,146	536,546	430,475	18.30

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	605,755	459,132	373,717	318,528	280,067
Developed Non-Producing	26,784	21,792	18,484	16,160	14,451
Undeveloped	269,435	142,559	80,283	44,242	21,089
TOTAL PROVED	901,975	623,483	472,483	378,929	315,606
PROBABLE	486,528	208,556	112,364	69,006	45,601
TOTAL PROVED PLUS PROBABLE	1,388,503	832,038	584,848	447,935	361,207

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS [(1)(2)]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	2,210,199	386,123	519,234	208,433	16,081	1,080,328	178,353	901,975
Total Proved plus Probable	3,571,540	652,939	895,048	272,459	20,564	1,730,530	342,027	1,388,503

Notes:
(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [(1)] ($/Bbl)	UNIT VALUE [(1)] ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	531,709.7	35.43	-
	Heavy Oil (including solution gas and other by-products)	6,514.2	27.21	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	14,123.8	-	1.63
	Total	552,347.7	-	-
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	673,262.0	30.37	-
	Heavy Oil (including solution gas and other by-products)	9661.1	26.17	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	23,223.5	-	1.65
	Total	706,146.6	-	-

Note:
(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   "**Economic Assumptions**" are the forecast prices and costs used in the estimate.

   Development and Production Status

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

   (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

      (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

      (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. "**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

5. "**Development costs**" means costs incurred to obtain access to our reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from our reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration

costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

8. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. "**Forecast Prices and Costs**"

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

12. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this statement assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS [(1)]

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	NATURAL GAS LIQUIDS		
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($Cdn/ Bbl)**	**Hardisty Bow River 25° API ($Cdn/ Bbl)**	**Hardisty Heavy 12° API ($Cdn/ Bbl)**	**AECO Gas Price ($Cdn/ MMbtu)**	**Edmonton Propane ($Cdn/Bbl)**	**Edmonton Butane ($Cdn/Bbl)**	**INFLATION RATES %/Year [(2)]**	**EXCHANGE RATE ($US/$Cdn) [(3)]**
Forecast									
2012	97.50	99.00	82.00	74.00	3.50	54.60	76.20	2.0	0.975
2013	97.50	99.00	82.00	74.00	4.20	56.40	79.80	2.0	0.975
2014	100.00	101.50	84.10	75.90	4.70	58.90	81.80	2.0	0.975
2015	100.80	102.30	84.70	76.50	5.10	60.40	82.40	2.0	0.975
2016	101.70	103.20	85.50	77.10	5.55	62.00	83.20	2.0	0.975
2017	102.70	104.20	86.30	77.90	5.90	63.40	84.00	2.0	0.975
2018	103.60	105.10	87.10	78.60	6.25	64.60	84.70	2.0	0.975
2019	104.50	106.00	87.80	79.20	6.45	65.60	85.40	2.0	0.975
2020	105.40	106.90	88.60	79.90	6.70	66.70	86.10	2.0	0.975
2021	107.60	109.20	90.40	81.60	6.85	68.10	88.00	2.0	0.975
2022	109.70	111.30	92.20	83.20	6.95	69.40	89.70	2.0	0.975
2023	111.90	113.50	94.00	84.80	7.05	70.60	91.50	2.0	0.975
2024	114.10	115.80	95.90	86.50	7.20	72.10	93.30	2.0	0.975
2025	116.40	118.10	97.80	88.20	7.40	73.70	95.20	2.0	0.975
2026	118.80	120.50	99.80	90.10	7.55	75.20	97.10	2.0	0.975
Thereafter	+2% /year	+2% /year	+2% /year	+2% /year	+2% /year	+2% /year	+2% /year	2.0	0.975

Notes:
(1) As at January 1, 2012.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2011, including price risk management activities, were $3.93/Mcf for natural gas, $94.76/Bbl for light and medium crude oil, $69.16 for heavy oil and $70.84/Bbl for NGLs.

Reserves Reconciliation

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2010	4,835.6	3,345.7	8,181.3	4.6	2.0	6.6
Discoveries	-	-	-	-	-	-
Extensions	5,750.0	3,520.9	9,271.0	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	2.6	0.7	3.3	-	-	-
Technical Revisions	1,890.6	(706.9)	1,183.6	-	-	-
Acquisitions	6,948.1	2,855.1	9,803.2	302.4	149.3	451.7
Dispositions	(0.6)	(0.3)	(0.9)	(4.1)	(2.0)	(6.1)
Economic Factors	-	-	-	-	-	-
Production	(1,198.8)	-	(1,198.8)	(27.7)	-	(27.7)
December 31, 2011	18,227.5	9,015.0	27,242.5	275.2	149.3	424.5

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2010	17,643.8	10,782.9	28,426.8	476.5	274.2	750.7
Discoveries	-	-	-	-	-	-
Extensions	8,172.0	4,716.7	12,888.8	254.5	154.2	408.6
Infill Drilling	-	-	-	-	-	-
Improved Recovery	6.6	1.6	8.3	0.2	-	0.2
Technical Revisions	1,529.0	(1,704.2)	(175.2)	69.6	(32.1)	37.5
Acquisitions	14,178.8	6,071.2	20,250.0	272.3	93.1	365.4
Dispositions	(40.7)	(66.4)	(107.1)	(0.3)	(0.1)	(0.4)
Economic Factors	-	-	-	-	-	-
Production	(4,484.3)	-	(4,484.3	(117.8)	-	(117.8)
December 31, 2011	37,005.3	19,801.8	56,807.1	955.0	489.2	1,444.2

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. 97% of our undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a two year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-
2009	75.0	75.0	-	-	64.5	64.5	1.8	1.8
2010	1,798.3	1,798.3	2.8	2.8	5,223.5	5,223.5	137.9	137.9
2011	7,017.8	7,699.4	118.3	121.1	6,980.6	8,616.5	195.6	233.7

The majority of our proved undeveloped reserves evaluated in the McDaniel Report are attributable to our Valhalla and Pembina properties. Proven undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proven undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. McDaniel has assigned 9.5 MMboe of undeveloped reserves in the McDaniel report with $203.5 million of associated undiscounted capital, of which $190.3 million is forecast to be spent in the first 2 years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-
2009	12.0	12.0	-	-	10.3	10.3	0.3	0.3
2010	2,017.4	2,017.4	1.4	1.4	4,813.4	4,813.4	118.4	118.4
2011	4,517.2	4,955.9	93.1	95.3	5,765.2	7,116.3	143.8	171.8

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. McDaniel has assigned 6.4 MMboe of probable undeveloped reserves in the McDaniel report with $59.1 million of associated undiscounted capital, all of which is forecast to be spent in the first 2 years.

Significant Factors or Uncertainties

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2012	128,436.1	162,432.5
2013	65,081.9	93,266.9
2014	14,618.1	15,434.4
2015	-	162.4
2016	-	23.0
Remaining	296.9	1,140.0
Total (Undiscounted)	208,433.0	272,459.2

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop those reserves could have a negative impact on our future cash flow.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2011. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Peace River Arch

The Valhalla North property is located in the Peace River Arch area of Alberta and is characterized by shallow declines and a predictable production base. The primary reservoir that Whitecap is currently focused on is the Montney Sexsmith oil pool and associated waterflood. The key characteristics of the pool are light 36^{o} API oil, homogeneous reservoir quality and no original moveable water formation.

West Central Alberta

Our Cardium producing areas are located in East Pembina, South Pembina and the Willesden Green area of West Central Alberta. The key characteristics of the Cardium in WCAB are light 40^{o} API oil with geology and oil resource mapping that is well defined with legacy vertical wells. There is no significant mobile formation water in the Cardium which leads to stable and predictable low decline production profiles.

Southwest Saskatchewan

This project is located at Fosterton in Southwest Saskatchewan and consists of Roseray and Cantuar oil pools. The key characteristics of these pools include medium 22^{o} API oil, stable and predictable low decline production profile and consistent and repeatable economics.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2011.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	224	146.3	22	10.8	126	74.6	154	60.6
Saskatchewan	109	57.6	46	22.0	-	-	2	0.9
Total	333	203.9	68	32.8	126	74.6	156	61.5

Of the non-producing wells, none were wells drilled in 2012 that were capable of production and had reserves assigned to them. In addition, as of the date of this Annual Information Form, none of these wells have been placed on production.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2011.

	DEVELOPED ACRES		UNDEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	110,195	66,456	77,056	49,696	187,251	116,152
Saskatchewan	11,428	5,966	21,714	20,318	33,142	26,285
Total	121,622	72,423	98,771	70,014	220,393	142,437

Rights to explore, develop and exploit 17,000 net acres of these undeveloped land holdings could expire by December 31, 2012 if not continued.

Whitecap calculates its developed and undeveloped acres based on individual leases.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 5 to our financial statements for the year ended December 31, 2011.

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2011 we had 392 net wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs that we expect to incur, net of estimated salvage values, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2011	20,598	4,234
Anticipated to be paid in 2012	173	172
Anticipated to be paid in 2013	39	37
Anticipated to be paid in 2014	328	263

The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The McDaniel Report only deducted $20.6 million (undiscounted) and $4.2 million (10% discount) for abandonment costs of wells with proved and probable reserves, in estimating the future net revenues disclosed in this Annual Information Form.

Tax Horizon

Based on estimated 2012 cash flow and capital expenditures, we do not expect to be cash taxable in 2012. Whitecap estimates it will not become taxable until 2015.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2011.

Expenditure	Year Ended December 31, 2011 ($000s)
Property acquisition costs – Unproved properties (1)	4,284
Property acquisition costs – Proved properties (2)	41,373
Corporate acquisition costs (3)	171,664
Exploration costs (4)	1,790
Development costs (5)(6)	133,237
Other	1,147
Total	353,495

Notes:
(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Cash-based.
(4) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(5) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(6) Net of drilling credits.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2011.

	Development		Exploratory	
	Gross	Net	Gross	Net
Natural Gas	-	-	1.0	0.5
Light and Medium Oil	52.0	41.7	-	-
Dry	-	-	-	-
Total	52.0	41.7	1.0	0.5

In 2012, we expect to drill approximately 47 oil wells in Alberta and 48 oil wells in Saskatchewan

Finding and Development Costs

The following table summarizes our 2011 finding and development costs.

($/Boe)	2011 (1)(2)(3) Proved	Proved plus Probable
Finding, development and acquisition cost	27.90	20.80
Finding and development costs	24.13	17.83
Acquisition costs	31.55	23.56

Notes:

(1) Including changes in future development capital expenditures.

(2) We have presented finding and development costs both including and excluding acquisitions and dispositions. While NI 51-101 requires that the effects of acquisitions and dispositions be excluded, we have included these items because we believe that acquisitions and dispositions can have a significant impact on our ongoing reserve replacement costs and that excluding these amounts could result in an inaccurate portrayal of our cost structure.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2011, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved					
West Central Alberta	3,248	-	6,727	165	4,534
Peace River Arch	1,390	-	5,985	110	2,497
Saskatchewan	1,015	15	687	-	1,144
Other	20	102	2,996	17	639
Total	5,673	117	16,395	292	8,815
Total Proved plus Probable					
West Central Alberta	3,528	-	7,200	175	4,903
Peace River Arch	1,482	-	6,283	116	2,645
Saskatchewan	1,047	15	701	1	1,180
Other	22	106	3,305	17	695
Total	6,079	121	17,489	309	9,423

Production History

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	Quarter Ended 2011				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2011**
Average Daily Production [1]					
Light and Medium Oil (bbls/d)	1,645	3,034	3,710	4,379	3,201
Heavy Oil	-	121	95	95	78
Natural Gas Liquids	181	223	355	474	309
Gas (MMcf/d)	6,666	11,770	13,951	17,150	12,417
Combined (boe/d)	2,937	5,339	6,485	7,806	5,657
Average Net Production Prices Received					
Light and Medium Oil ($/bbl)	84.32	99.55	90.89	98.51	94.81
Heavy Oil	-	69.39	62.37	74.73	69.16
Natural Gas Liquids	67.54	69.09	68.69	74.49	70.84
Gas ($/Mcf)	4.20	4.22	3.92	3.38	3.84
Combined ($/boe)	58.19	66.21	66.46	67.81	65.81
Royalties Paid					
Light and Medium Oil ($/bbl)	15.16	13.92	11.85	10.49	12.28
Heavy Oil	-	12.23	11.99	13.89	12.60
Natural Gas Liquids	15.16	13.92	11.85	10.49	12.28
Gas ($/Mcf)	0.17	0.07	0.37	0.43	0.28
Combined ($/boe)	9.44	8.82	7.81	6.85	7.93
Production Costs [2][3]					
Light and Medium Oil ($/bbl)	21.68	21.66	21.45	21.66	21.60
Heavy Oil	-	20.25	25.01	22.28	21.15
Natural Gas Liquids	21.68	21.66	21.45	21.66	21.60
Gas ($/Mcf)	3.63	2.29	2.07	3.10	2.50
Combined ($/boe)	12.93	11.14	11.95	12.02	11.91
Netback Received					
Light and Medium Oil ($/bbl)	47.49	63.96	57.59	66.36	60.92
Heavy Oil	-	36.91	25.36	38.57	35.42
Natural Gas Liquids	30.71	33.51	35.39	42.34	36.96
Gas ($/Mcf)	0.40	1.86	1.48	(0.14)	1.07
Combined ($/boe)	35.82	46.25	46.70	48.94	45.97

Notes:

(1) Before the deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.

(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2011.

	Crude Oil (Bbls/d)	**Natural Gas Liquids (Bbls/d)**	**Natural Gas (Mcf/d)**	**BOE (Boe/d)**
Peach River Arch	857	142	5,114	1,853
West Central Alberta	1,886	147	4,465	2,779
Southwest Saskatchewan	258	-	282	306
Minor	273	16	2,552	720
Total	3,274	305	12,413	5,657

CHANGES TO RESERVES DATA

Subsequent to December 31, 2011, we completed the acquisition of Compass. The assets acquired by us pursuant to the acquisition of Compass consisted of operated, high working interest light oil assets located predominately in Dodsland/Kindersley area of West Central Saskatchewan with the majority of production and reserves focused in the Viking formation and which represents a new light oil resource area for us. The Total proved plus probable reserves and total proved reserves for the assets acquired pursuant to the acquisition by Compass effective December 31, 2011 as determined by David Mombourquette, our Vice-President, Business Developmentwho is a qualified reserves evaluator in accordance with NI 51-101 were 5,556 Mboe (75% light oil and NGLs) and 3,784 Mboe (76% light oil and NGLs) respectively (in each case based on Compass' gross reserves).

Further information on Compass' reserve information, as at December 31, 2011, as prepared by David Mombourquette, our Vice-President, Business Development in accordance with the COGHE Handbook who is a qualified reserves evaluator in accordance with NI 51-101 is set forth below. The reserves data set forth below used the same pricing and inflation rate assumptions set forth above under "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*".

Summary of Oil and Gas Reserves
as at December 31, 2011
Based On Forecast Prices and Costs

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**
PROVED:								
Developed Producing	1,088.6	955.1	32.2	30.6	2,682.1	2,289.0	53.3	45.5
Developed Non-Producing	26.0	25.7	-	-	235.7	209.5	4.7	4.7
Undeveloped	1,535.8	1,351.3	77.9	64.3	2,500.6	2,175.3	47.8	41.4
TOTAL PROVED	2,650.4	2,332.1	110.2	94.9	5,418.5	4,673.8	105.8	91.6
PROBABLE	1,168.1	1,027.5	45.3	39.2	3,025.1	2,605.3	58	51.2
TOTAL PROVED PLUS PROBABLE	3,818.5	3,359.6	155.5	134.1	8.443.6	7,279.1	163.8	142.8

Summary of Present Values of Future Net Revenue
as at December 31, 2011
Based on Forecast Prices And Costs

	Before Income Taxes Discounted at (%/Year)					Unit Value before Income Tax
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**Discounted at 10%/yr ($/BOE)**
PROVED:						
Developed Producing	63,574.3	55,340.2	49,228.1	44,528.2	40,810.4	30.37
Developed Non-Producing	3,320.3	2,459.2	1,933.2	1,587.9	1,347.2	27.62
Undeveloped	51,010.3	37,619.4	27,800.3	20,414.9	14,733.8	13.38
TOTAL PROVED	117,906.0	95,418.8	78,961.6	66,531.0	53,584.9	20.95
PROBABLE	82,117.2	61,396.5	48,203.3	39,328.0	36,373.5	27.15
TOTAL PROVED PLUS PROBABLE	200,023.3	156,815.3	127,164.9	105,859.0	89,958.4	22.93

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We have an extendible revolving Credit Facility with a syndicate of lenders. The borrowing base under the Credit Facility was increased to $250 million from $190 million in connection with the acquisition of Compass. The Credit Facility bears interest at the bank's prime lending or bankers' acceptance rates plus applicable margins. The Credit Facility is secured by a $400 million demand debenture in respect of all of our assets and a general assignment of book debts in respect of all of our accounts. Under the Credit Facility, we must maintain a working capital ratio of not less than 1 to 1 at all times. The working capital ratio is defined as current assets (including the undrawn availability under the Credit Facility) to current liabilities (excluding any current portion of amounts drawn under the Credit Facility). The borrowing base is generally subject to review and redetermination by the lenders on an annual basis or in the event of a change in our borrowing base properties (due to a disposition of assets beyond certain defined limits or a change which results in a material adverse effect, as determined by the lenders). The borrowing base is scheduled for review on or before May 31, 2012 and there can be no assurance that the current borrowing base level will be maintained. Whitecap anticipates increasing its Credit Facility to $400 million following closing of the Acquisition. See "*Risk Factors – Credit Facility Arrangements*".

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Subject to the provisions of the *Business Corporations Act* (Alberta), holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by our Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares without nominal or par value. Our Board of Directors may issue preferred shares at any time and from time to time in one or more series and shall fix the number of preferred shares in such series and determine the designation, rights, privileges, restrictions and conditions attaching the preferred shares. The preferred shares shall be entitled to priority over our Common Shares and over any other of our shares ranking junior to the preferred shares with respect to priority in the payment of dividends if, as and when declared by our Board of Directors and the receipt of our remaining property upon liquidation, dissolution or winding-up. There are currently no preferred shares issued or outstanding.

MARKET FOR OUR SECURITIES

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "WCP" and commenced trading on the Toronto Stock Exchange on October 18, 2010. Additionally, our outstanding subscription receipts trade on the TSX under the trading symbol "WCP.R" and commenced trading on the Toronto Stock Exchange on March 19, 2012. See "*General Development of our Business – Recent Developments - Midway Acquisition*".

The following sets out the high and low trading prices and aggregate volume of trading for the periods noted below for the Common Shares:

Period	High	Low	Volume
2011			
March	$7.37	$6.20	2,465,962
April	$7.49	$6.68	8,852,056
May	$7.12	$6.51	3,238,660
June	$6.66	$6.01	3,793,116
July	$7.60	$6.20	6,641,094
August	$7.19	$6.10	1,662,439
September	$7.34	$5.44	4,699,808
October	$7.22	$4.82	6,313,701
November	$8.56	$6.79	8,907,397
December	$8.70	$7.52	7,366,111
2012			
January	$9.60	$8.33	13,735,482
February	$10.77	$9.28	22,128,517
March (1 - 20)	$9.90	$9.20	15,216,000

The following sets out the high and low trading prices and aggregate volume of trading for the periods noted below for the outstanding subscription receipts:

Period	High	Low	Volume
2012			
March (19-20)	$9.40	$9.20	332,100

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Grant B. Fagerheim (2) Calgary, Alberta	President, Chief Executive Officer and Director	June 2008	Our President and Chief Executive Officer since June 2008; President and Chief Executive Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company from January 2005 to September 2008.
Donald G. Cowie (1)(4)(5) Calgary, Alberta	Director	April 2011	Mr. Cowie is currently President of JOG Capital Inc., a private equity partnership focused on junior oil and gas companies in Western Canada. He has over 25 years of experience in the financial oil and gas industry. From 1992 to 2002, Mr. Cowie was the head of corporate and investment banking for the Bank of America. Prior to 2002, he served as an officer or director for several junior oil and gas companies and several other financial companies specializing in the oil and gas sector.
Gregory S. Fletcher (1)(2) Calgary, Alberta	Director	September 2010	President of Sierra Energy Inc., a private oil and gas production company.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Glenn A. McNamara (2)(3) Calgary, Alberta	Director	September 2010	Mr. McNamara is the Chief Executive Officer and a director of Petromanas Energy Inc., a public oil and gas company. From August 2005 to August 2010, he was the President of BG Canada (part of the BG Group PLC, a public gas company with its head office in the United Kingdom, trading on the London Stock Exchange). Prior thereto he was the President of ExxonMobil Canada Energy Corp. (a public oil and gas company).
Stephen C. Nikiforuk (1) Calgary, Alberta	Director	August 2009	President of MyOwnCFO Professional Corporation since October 2011 and President of MyOwnCFO Inc. since July 2009 (both private companies); Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011; Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008.
Robert G. Welty (3)(4)(5) Calgary, Alberta	Director	August 2009	President of Escondido Resources Ltd. (a private oil and gas company); Chief Executive Officer of Sterling Resources Ltd. (a public oil and gas company) from May 2000 to December 2006 and Chairman of Sterling Resources Ltd. from May 2000 to May 2007.
Grant A. Zawalsky (3) Calgary Alberta	Director	August 2009	Partner of Burnet, Duckworth & Palmer LLP, Barristers and Solicitors.
Joel Armstrong Calgary, Alberta	Vice President, Production and Operations	May 2010	Our Vice President, Production and Operations since May 2010; President of Maxwell Energy Inc. (a private oil and gas company) from September 2009 to May 2010; Vice President, Operations of Ridgeback Exploration Ltd. (a private oil and gas company) from May 2005 to July 2009.
Daniel Christensen Calgary, Alberta	Vice President, Exploration	September 2009	Our Vice President, Exploration since September 2009; Vice President, Exploration of Capex Exploration Ltd. (a private oil and gas company) from January 2005 to September 2008.
Darin Dunlop Calgary, Alberta	Vice President, Engineering	November 2009	Our Vice President, Engineering since November 2009; President of ReKon Energy Inc. (a private oil and gas company) from August 2009 to December 2009; Vice President, Engineering of Ridgeback Exploration Ltd. (a private oil and gas company) from March 2005 to August 2009.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Thanh Kang Calgary, Alberta	Vice President, Finance and Chief Financial Officer	September 2009	Our Vice President, Finance and Chief Financial Officer since September 2009; Vice President, Finance and Chief Financial Officer of Churchill Energy Inc. (a public oil and gas company) from January 2005 to September 2008.
Gary Lebsack Calgary, Alberta	Vice President, Land	September 2009	Our Vice President, Land since September 2009; Vice President, Land of Glamis Resources Ltd. (a public oil and gas company) from January 2006 to July 2009.
David Mombourquette Calgary, Alberta	Vice President, Business Development	September 2009	Our Vice President, Business Development since September 2009; Vice President, Business Development of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company from January 2005 to September 2008.

Notes:
(1) Member of our audit committee.
(2) Member of our reserves committee.
(3) Member of our corporate governance and compensation committee.
(4) Mr. Cowie was appointed to our board of directors effective April 25, 2012.
(5) Effective May 17, 2011, Mr. Welty was replaced by Mr. Cowie on our audit committee.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at March 20, 2012 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 7.2 million Common Shares or approximately 8% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Zawalsky who was a former director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005 and Mr. Fagerheim who was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in February 2009.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our audit committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our audit committee are Mr. Nikiforuk (Chair), Mr. Cowie (who replaced Mr. Welty effective May 17, 2011) and Mr. Fletcher, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

Stephen C. Nikiforuk: *MyOwnCFO Inc. and MyOwnCFO Professional Corporation*

Mr. Nikiforuk has been the President of MyOwnCFO Professional Corporation since October 2011 and President of MyOwnCFO Inc. since July 2009, both private companies. Before then, Mr. Nikiforuk was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011. Before then, Mr. Nikiforuk was the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008. Mr. Nikiforuk is an active Chartered Accountant.

Donald G. Cowie*: JOG Capital Inc.*

Mr. Cowie is currently President of JOG Capital Inc., a private equity partnership focused on junior oil and gas companies in Western Canada. He has over 25 years of experience in the financial oil and gas industry. From 1992 to 2002, Mr. Cowie was the head of corporate and investment banking for the Bank of America. Prior to 2002, he served as an officer or director for several junior oil and gas companies and several other financial companies specializing in the oil and gas sector. In these roles, Mr. Cowie has acquired significant experience and exposure to accounting and financial reporting issues.

Gregory S. Fletcher: *Sierra Energy Inc.*

Mr. Fletcher is an independent businessman involved in the oil and natural gas industry in western Canada. He has considerable business experience in the junior sector of the oil and natural gas industry and is currently President of Sierra Energy Inc., a private oil and natural gas company that he founded in 1997. Mr. Fletcher is also a director Peyto Exploration & Development Corp., a public oil and natural gas company, a director of Calfrac Well Services Ltd., a public oilfield service company and a director of Total Energy Services Inc., a public oilfield service company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. During 2009, Mr. Fletcher completed the Director Education Program developed by the Institute of Corporate Directors and the Rotman School of Management in conjunction with the Haskayne School of Business. Mr. Fletcher holds a BSc. in geology from the University of Calgary.

Pre-Approval of Policies and Procedures

Our Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to us by our external auditors and will consider the impact on the independence of such auditors. The Audit Committee delegated to the Audit Chair the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting such pre-approval and the Chair complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

PricewaterhouseCoopers LLP are our auditors. PricewaterhouseCoopers LLP have been our auditors since October 2009. Prior to the completion of the reverse takeover transaction, Spitfire's auditors were Meyers Norris Penny LLP.

Fees we incurred with PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2011	Fees Paid to Auditor in Year Ended December 31, 2010
Audit Fees (1)	$162,500	$142,200
Audit-Related Fees (2)	$35,000	$23,600
Tax Fees (3)	$82,800	$43,000
All Other Fees (4)	$52,000	$-
Total	$315,300	$208,800

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as audit fees. The services provided in this category include due diligence assistance, accounting consultations on proposed transactions, and consultation on International Financial Reporting Standards ("**IFRS**") conversion.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit services.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since commencement to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

We have not declared or paid any dividends on our Common Shares since our inception and no dividends were declared or paid on the Spitfire Shares since its inception. Any decision to pay dividends on our Common Shares will be made by our Board of Directors on the basis of our earnings, financial requirements and other conditions existing as such future time. We currently do not have a dividend policy.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May

27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The

New Well Royalty Regulation, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in

Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

We do not own of have working interests in facilities that meet or are expected to exceed the emissions threshold.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

We do not own or have working interests in facilities that are subject to reporting or reporting/verification requirements.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves that we may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, our management may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by us.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects. In accordance with industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event we could incur significant costs.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by us is and will continue to be affected by numerous factors beyond our control. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas to commercial markets. We may also be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of our Common Shares that are unrelated to our performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which our Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of, so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Operational Dependence

Other companies operate some of the assets in which we have an interest. As a result, we have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others therefore depends upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that we produce.

Gathering and Processing Facilities and Pipeline Systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and require us to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. We may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact our production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by independent evaluators.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, which could negatively impact the market price of the Common Shares.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of the capital markets, our credit rating (if applicable), interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and our securities in particular. Further, our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. As a result of the global economic volatility, we, along with many other oil and natural gas entities, may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

Under our Credit Facility, the amount authorized thereunder is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under our Credit Facility and in the event that we do not comply therewith our access to capital could be restricted or repayment could be required. Our failure to comply with such covenants, which may be affected by events beyond our control, could result in the default under our Credit Facility which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing, the lenders under our Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may, from time to time, impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our borrowing base is determined and re-determined by our lenders based on our reserves, commodity prices, applicable discount rate and other factors as determined by our lenders. A material decline in commodity prices could reduce our borrowing base, therefore reducing the funds available to us under the Credit Facility which could result in a portion, or all, of our bank indebtedness be required to be repaid.

We anticipate increasing the borrowing base of our Credit Facility to $400 million in connection with the Arrangement There is a risk that we may not be able to increase our Credit Facility in connection with the Arrangement to the level anticipated and on terms acceptable to it and there can be no assurance that the Credit Facility will be increased to the amounts and in the timeframes anticipated.

Issuance of Debt

From time to time we may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;

- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;

- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or

- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by us is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Dividends

We have not paid any dividends on our outstanding Common Shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and our financial condition, the need for funds to finance ongoing operations and other considerations as our board of directors considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on our business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Conflicts of Interest

Certain of our directors are also directors of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, is our credit agreement in respect of our Credit Facility, which is available on our SEDAR profile at www.sedar.com.

Subsequent to our most recently completed financial year we have also entered into the Arrangement Agreement, the Underwriting Agreement and Subscription Receipt Agreement, all of which are described in more detail under "*General Development of Our Business – History and Development – Recent Developments – Midway Acquisition*" and which are available on our SEDAR profile at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us, other than as disclosed herein.

AUDITORS

PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3, is our auditor.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Olympia Trust Company at its principal offices in Calgary, Alberta and in Toronto, Ontario.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator and PricewaterhouseCoopers LLP, our independent auditors.

We used PricewaterhouseCoopers LLP for external audit and tax advisory services for the fiscal year ended December 31, 2011. PricewaterhouseCoopers LLP has advised us that they are independent with respect to us within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates, except for Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at www.sedar.com and on our website at www.wcap.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans is contained in our proxy materials relating to our annual and special shareholders meeting to be held on April 20, 2012. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2011 and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Whitecap Resources Inc.
Suite 500, 222 – 3rd Avenue S.W.
Calgary, Alberta, T2P 0B4
Tel: (403) 266-0767
Fax: (403) 266-6975

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE FORM 51-101F3

Management of Whitecap Resources Inc. ("**Whitecap**") is responsible for the preparation and disclosure of information with respect to Whitecap's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Whitecap's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Whitecap has:

(a) reviewed Whitecap's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed Whitecap's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*Grant B. Fagerheim*"
Grant B. Fagerheim
Chairman, President and Chief Executive Officer

(signed) "*Glenn A. McNamara*"
Glenn A. McNamara
Director, Chairman of the Reserves Committee and Member of the Compensation and Corporate Governance Committee

(signed) "*Darin Dunlop*"
Darin Dunlop
Vice President Engineering

(signed) "*Gregory S. Fletcher*"
Gregory S, Fletcher
Director and Member of the Audit Committee and the Reserves Committee

March 20, 2012

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR FORM 51-101F2

To the board of directors of Whitecap Resources Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (County or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	Corporate Summary February 29, 2012	Canada	-	706,147	-	**706,147**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our reports for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

   Executed as to our report referred to above:

   McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, February 29, 2012.

"ORIGINALLY SIGNED BY"

C.B. Kowalski, P. Eng.
Vice President

APPENDIX C

MANDATE & TERMS OF REFERENCE
OF THE
AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors of Whitecap Resources Inc. ("**Whitecap**") to which the board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Whitecap and related matters;

2. To provide good communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To review the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Whitecap, none of whom are members of management of Whitecap and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in National Instrument 52-110 - Audit Committees ("**NI 52-110**"). Provided that in the event that the common shares of Whitecap trade on the facilities of the TSX Venture Exchange, the Committee shall be comprised of at least three (3) directors of Whitecap, the majority of whom shall be "independent" (as such term is used in NI 52-110) in reliance of the exemptions afforded to venture issuers under NI 52-110.

2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate". The Board of Directors of Whitecap has adopted the definition for "financial literacy" used in NI 52-110.

Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.

3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken and shall be made available to the board. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

5. The Committee shall meet with the external auditor at least quarterly (including without management present) and at such other times as the external auditor and the audit Committee consider appropriate.

6. The auditor of Whitecap is entitled to receive notice of every meeting of the Committee and be heard thereat.

7. Meetings may be held by way of telephone conference call.

8. A written resolution signed by all Committee members entitled to vote on that resolution at a meeting of the Committee is as valid as one passed at a Committee meeting.

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Whitecap's Internal Control Systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Whitecap and the notes thereto prior to their submission to the board of directors for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation and reserves with respect to environmental matters;

   - reviewing accounting treatment of unusual or non-recurring transactions;

   - ascertaining compliance with covenants under loan agreements;

   - reviewing disclosure requirements for commitments and contingencies;

   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

- reviewing unresolved differences between management and the external auditors; and

- obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**"), annual reports and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Whitecap's disclosure of all other financial information and shall periodically assess the accuracy of those procedures. The Committee shall also review Whitecap's policies and procedures for making and updating disclosures on Whitecap's website and shall periodically assess the adequacy and accuracy of such policies and procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:

   - ensure the auditor's ultimate accountability to the board of directors and the Committee as representatives of the shareholders and as such representatives, to evaluate the performance of the auditor;

   - recommend to the board the appointment of the external auditors;

   - recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

   - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors;

   - ensure that the auditor submits on a periodic basis to the Committee, a formal written statement delineating all relationships between the auditor and Whitecap, consistent with Canadian and other applicable auditor independence standards, and to review such statement and to actively engage in a dialogue with the auditor with respect to any undisclosed relationships or services that may impact on the objectivity and independence of the auditor, and to review the statement and dialogue with the board of directors and recommend to the board of directors appropriate action to ensure the independence of the auditor;

   - provide a line of communication between the auditors and the board of directors; and

   - meet with the auditors at least once per quarter without management present to allow a candid discussion regarding any concerns the auditors may have and to resolve any disagreements between the auditor and management regarding Whitecap's financial reporting.

6. Review with external auditors (and internal auditor if one is appointed by Whitecap) their assessment of the internal controls of Whitecap, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Whitecap and its subsidiaries.

7. The Committee must pre-approve all non-audit services to be provided to Whitecap or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review risk management policies and procedures of Whitecap (i.e. hedging, litigation and insurance).

9. The Committee shall establish a procedure for:

- the receipt, retention and treatment of complaints received by Whitecap regarding accounting, internal accounting controls or auditing matters; and

- the confidential, anonymous submission by employees of Whitecap of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve Whitecap's hiring policies regarding employees and former employees of the present and former external auditors of Whitecap.

11. The Committee shall have the authority to investigate any financial activity of Whitecap. All employees of Whitecap are to cooperate as requested by the Committee.

12. The Committee shall review all related party transactions.

13. The Committee shall review the status of taxation matters of Whitecap and its major subsidiaries.

14. The Committee shall review the short term investment strategies respecting the cash balance of Whitecap.

15. The Committee shall conduct or undertake such other duties as may be required from time to time by any applicable regulatory authorities, including the TSX.

16. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Whitecap without any further approval of the board.